IPTC 13915

Observations of Open Fractures in Carbonate Reservoir Rocks, Implications for Fluid Flow Simulations

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This abstract was prepared for presentation at the International Petroleum Technology Conference held in Doha, Qatar, 7–9 December 2009.

Abstract

Fractured carbonate reservoirs are commonly extremely heterogeneous. This heterogeneity is caused by fracturing at multi scales superimposed on inherent textures from deposition and diagenesis. In addition, there is an interrelationship between diagenesis and fracture formation, e.g. the matrix properties may change due to reactions with fluids provided by the fracture network or fractures are filled with calcite cement.

The aim of this study is first to describe individual fractures and the fracture network of some typical fractured carbonate reservoirs, and secondly to discuss their importance for fluid flow in the reservoir. Finally, it will be outlined how these findings should be incorporated into static and dynamic reservoir models.

Traditionally fluid flow in fractured reservoirs is simulated using dual porosity or dual porosity/dual permeability formulation based on the work of Warren and Root (1963). Each cell in the simulation models is typically 100*100*10m and characterized by one value of fracture permeability (tensor) and one fracture porosity. The matrix-fracture fluid exchange is described using a transfer function which is commonly regarded to be proportional via shape factor to the block-size, which is kept constant within one simulation cell.

However, this simplistic image of a fractured reservoir only partly captures the internal fracture features and fracture network geometry as observed in core or outcrop analogues of reservoir rocks. Firstly, the majority of fractures in core are only partly open. This implies that flow within fractures will tend to be channelized instead of fissure type flow. Furthermore, the parts of the fracture which are open do show a variable amount of calcite cement between the matrix and the open void. The calcite cement on the fracture planes inhibits transfer of fluid between matrix and fracture. This implies that the fracture matrix transfer function is not only controlled by the geometry of the matrix blocks, but also by the area of the fracture plane, adjacent to the matrix block, which is not coated with cement. Finally, the fracture fill form bridges between the two sides of the fracture will keep the fractures open during pressure depletion in the reservoir.

Layering and bed parallel stylolites do also have a significant effect on fracture network geometry as fractures commonly terminates against these features. The combination of stylolites and open fractures do result in complicated flow patterns as demonstrated by use of CT-scan monitoring of gas flooding experiments of core samples (Wennberg et al 2009)

Outcrop studies in the Zagros of SW Iran show that several fracture sets coexist in anticlines which are outcrop analogues to hydrocarbon fields in the area. The fractures generate very complex fracture network geometries and four distinct fracture sets have been recognized. Set A and B are parallel and perpendicular to the fold axis respectively. Set C and D are oblique and symmetric to the fold axis. The presence of more than 2 fracture sets implies that the matrix block in general has a non-rectangular shape.

It is well known that fracture spacing is dependent on the mechanical stratigraphy, i.e. the spatial variation in mechanical properties due to changes in lithology or other matrix properties. The mechanical stratigraphy is controlled by the depositional environment and subsequent diagenesis. In this study the distribution of fracture spacing have been investigated using the coefficient of variance (Cv) which is the standard deviation divided by the

average fracture spacing (Gillespie et al. 2001). Cv equals 0 for a regular spacing, Cv equals 1 for random spacing distribution and Cv > 1 implies clustering of fractures. Fracture spacing investigated in Cretaceous and Tertiary outcrops of reservoir analogues is not regular as shown by a coefficient of variance ranging between 0.4 and 2. The majority of Cv values are close to 1 i.e. the fracture spacing do dominantly have a random distribution. Hence, both the shape and the size of matrix blocks do indeed have large variation within a rock volume equivalent of a simulation model cell.

Both the distribution of cement within a fracture and the fracture spacing characteristics described above will have an important impact on the fluid flow and recoverable reserves in fractured reservoirs. Hence, these characteristics should be taken into account when building reservoir models and when analysing the results of the simulation model. Furthermore, the observations above demonstrate the importance of an integrated multi-disciplinary study of fractures characterization and modelling. Improving static modelling, followed by dynamic simulation, of naturally fractured reservoirs, requires involvement of all disciplines including sedimentology, diagenesis, structural geology, petrophysics, geophysics, well test analysis, core analysis and reservoir engineering as well as drilling and production engineering.

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